Supplemental Direct Testimony and Schedule
Timothy J. O'Connor

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-15-826
Exhibit___(TJO-2)

Prairie Island Plant Operations:
Life Cycle Management Capital Investments

January 29, 2016

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Timothy J. O'Connor. I am the Chief Nuclear Officer (CNO) for Northern States Power Company (Xcel Energy or the Company). I am responsible for all nuclear activities at the Monticello Nuclear Generating Plant (Monticello) and the Prairie Island Nuclear Generating Plant (Prairie Island).

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony on behalf of Northern States Power Company regarding Nuclear Operations.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. The purpose of this testimony is to address the Nuclear operations aspects of the requirement in the Commission's December 22, 2015 Notice and Order for Hearing (December 22 Order) that the Company provide Supplemental Direct Testimony regarding Prairie Island Life Cycle Management (LCM) costs from 2008 through 2020. Company witness Mr. Scott L. Weatherby provides the requested financial data through 2020. I provide the operational definition of LCM work and contrast LCM activities with other kinds of investments in a nuclear plant, in order to give proper context to Mr. Weatherby's analysis. I also provide the operational reasons why the Company's Prairie Island LCM investments for 2008 through 2015 are below the levels expected in the most recent updates to our Certificate of Need proceedings in 2012.

Finally, I address rate case Issue 8 identified in the Commission's December 22 Order, and explain why, from an operational standpoint, it is necessary to complete the Prairie Island LCM work included in our rate case during the term of our multi-year rate plan. My Direct Testimony addressed the reasons conducting this work is reasonable and prudent; in this Supplemental Direct Testimony I underscore why the work cannot reasonably be delayed beyond the term of this rate case. Therefore, the capital additions in our 2016 through 2018 plan years should be approved like other reasonable rate case investments, without conditioning recovery on longer-term decisions about Prairie Island's future operation.

Q. PLEASE SUMMARIZE YOUR SUPPLEMENTAL DIRECT TESTIMONY.

A. I begin by defining LCM, in order to provide context for a discussion of the LCM work we have completed and plan to complete at Prairie Island between 2008 and 2020. Specifically, I explain that Life Cycle Management is not a discrete project or set of projects. Rather, LCM relates to managing the aging of plant systems and equipment. Such aging management work consists of small, more routine projects, as well as larger capital investments like the Unit 2 steam generator project we completed in 2013.

I also explain why the Prairie Island capital investments included in our rate case are necessary over the next three to five years regardless of longer-term decisions that may be made regarding Prairie Island's continued operation. Many of the plant systems at Prairie Island were only intended to operate for the initial 40 years of the Units' operating licenses, and are nearing, at, or beyond the age at which they can continue to operate reliably or effectively. Through 2014, we were able to defer some LCM work through consistent

equipment inspections and maintenance. During that same time, we needed to focus resources on the Nuclear Regulatory Commission's (NRC) increasing safety and reliability requirements. By making the critical investments to fulfill NRC mandates while prioritizing investments in aging equipment where they were most needed, we complied with our regulatory obligations while maintaining and enhancing plant safety and achieving NRC Column 1 status. As a result, we were able to provide our customers with sustained operation at high capacity levels for a number of years and maximize the benefits of a reliable Prairie Island facility.

However, we can no longer delay capital investments in some of our oldest equipment. Rather, we have continuing obligations under our NRC operating license to keep our plant in good condition, and cannot operate the plant in a reasonably reliable manner over the next few years unless this work is completed. Because the overall need to complete the work outlined in my Direct and Supplemental Testimony is not contingent on the operation of Prairie Island beyond the term of this rate case, as the operator of this nuclear plant we need to move forward with these investments. We therefore believe the associated costs should be recovered in this rate case regardless of broader discussions regarding the longer-term future of Prairie Island.

Q. HOW IS YOUR SUPPLEMENTAL DIRECT TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the sections outlined below:

- Section II – Life Cycle Management Overview
- Section III – Past Prairie Island LCM Drivers
- Section IV – 2016-2020 MYRP Capital Investments in LCM
- Section V – Conclusion

II. LIFE CYCLE MANAGEMENT OVERVIEW

Q. GENERALLY SPEAKING, WHAT IS "LIFE CYCLE MANAGEMENT?"

A. LCM work at a nuclear plant consists of equipment investments over time to manage aging equipment, and to keep the plant operating in a safe and reliable manner during the current term of its operating license.

While there is no single universal definition of LCM activities, the Electric Power Research Institute (EPRI) defines LCM, life extension, and aging management for nuclear plants as "the activities a utility should successfully execute to maintain the material condition of the plant in a safe and cost-effective manner and to support operation up to and potentially beyond the originally licensed term."[1]

In other words, LCM activities are focused on the management of aging equipment and systems needed to the keep Prairie Island Units 1 and 2 operational in light of the 20-year extensions of their operating licenses beyond 2013 and 2014, respectively.

Q. IS LCM TYPICALLY COMPLETED AS A SINGLE PROJECT?

A. No. LCM is not a discrete project or set of projects. Rather, LCM consists of many different types of projects that are driven by equipment aging over the decades of plant operation. Some projects are multi-year efforts to address aging and involve significant planning (e.g., rewinding, replacing or refurbishing an electric generator), while other, smaller or more routine

[1] EPRI, *Utility Activities for Nuclear Power Plant Life Cycle Management and License Renewal* (May 1995) at 1-1, available online at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=TR-104751 (last visited Jan. 5, 2016).

projects are completed when the work is needed to keep the plant operating and functioning safely and reliably. An LCM project may be completed in a single year, or in phases. Minnesota Statutes and Rules do not require a Certificate of Need for LCM activities, which is logical given the need for this ongoing assessment of plant aging.

Q. ARE THERE INSTANCES WHEN IT MAKES SENSE TO COMPLETE LCM WORK IN CONJUNCTION WITH OTHER PROJECTS?

A. Yes. It can be cost-effective and efficient to complete certain kinds of LCM activities in conjunction with other work. At one time, we anticipated replacing some aging Prairie Island equipment – including our electric generators and generation step-up transformers – in conjunction with an extended power uprate (EPU) project, in order to avoid replacing the equipment once due to age and a second time to support increased plant generation capacity. Since the Prairie Island EPU has been cancelled, the associated LCM that is still necessary has been or will be completed over a longer span of time than anticipated earlier.

Q. IS ALL LCM WORK LIKE THE WORK COMPLETED AS PART OF THE MONTICELLO LCM/EPU PROGRAM?

A. No. In light of the preceding Monticello LCM/EPU Program, we believe there may be confusion about what constitutes LCM. We completed significant LCM work in conjunction with an EPU at Monticello in order to avoid replacing old equipment due to age and then separately going in to improve the same equipment to operate under EPU conditions. However, the LCM work that was completed with the Monticello EPU is not the only kind of LCM work; rather, in most instances the need for LCM work is identified,

planned, and implemented over time. It is simply ongoing management of aging systems and equipment over time.

Q. ARE ALL INVESTMENTS IN NUCLEAR PLANTS AND EQUIPMENT PART OF LCM?

A. No. As discussed above, LCM is focused on the effects of aging and obsolescence on equipment and systems, particularly when a plant's operating license has been extended beyond its originally anticipated useful life—as with Prairie Island. It does not include fuel or dry cask storage, property maintenance, mandated compliance work that includes new regulatory requirements arising out of events not driven by equipment obsolescence (e.g., Fukushima modifications and NFPA 805 safety requirements from our recent rate cases), or broad improvements in plant performance (e.g., an EPU). I discuss these categories in the context of Nuclear's current capital budget groupings later in my Supplemental Direct Testimony.

III. PAST PRAIRIE ISLAND LCM DRIVERS

Q. HOW HAS THE LCM WORK COMPLETED AT PRAIRIE ISLAND BETWEEN 2008 AND 2015 COMPARED, OVERALL, TO ESTIMATES IN THE COMPANY'S EARLIER FILINGS WITH THE COMMISSION?

A. As Mr. Weatherby discusses in his Supplemental Direct Testimony, between 2008 and 2015 the Company spent less on LCM work at Prairie Island than we anticipated at the time of our 2012 Change in Circumstances filing in the Prairie Island Certificate of Need docket.[2] Mr. Weatherby provides the data

[2] *In re Application of Northern States Power Company for a Certificate of Need for the Prairie Island Nuclear Generating Plant for an Extended Power Uprate*, Docket No. E002/CN-08-509, NOTICE OF CHANGED CIRCUMSTANCES AND PETITION at Attachment A (Mar. 30, 2012) (Notice of Changed Circumstances).

illustrating that between 2008 and 2015, we spent approximately $55 million less on Prairie Island LCM than we anticipated in 2012.

Q. WHY WERE THE PRAIRIE ISLAND LCM COSTS IN THIS PERIOD LOWER THAN PREVIOUSLY ANTICIPATED?

A. These costs were lower primarily because we carefully prioritized our investments in aging systems in light of plant needs and operations at the time, as well as the commitment of Company resources to increasing NRC regulatory requirements and other Company-wide needs. As a result of these strategies, we deferred some Prairie Island LCM work that we had initially expected to undertake in the 2012 through 2015 timeframe. During this period, we brought Prairie Island into NRC Column 1 status (thereby avoiding heightened regulatory scrutiny and the associated costs), enhanced the plant's safety systems, and obtained consistently high plant performance on behalf of our customers.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE INCREASING MANDATED COMPLIANCE COSTS DURING THIS PERIOD?

A. Yes. In recent years the NRC has steadily increased safety and reliability requirements for operating nuclear facilities. Company witness Mr. Weatherby's Exhibit___(SLW-1), Schedule 7 illustrates the increasing costs associated with those requirements. As an example, in our 2010 rate case Company witness Mr. Dennis L. Koehl explained that the Company was in the initial stages of assessing fire protections necessary for Prairie Island in light of 10 CFR 50.48(c).[3] Between 2009 and 2015, the Company incurred costs of approximately $49 million to address NRC requests and implement

[3] Docket No. E002/GR-10-971, Koehl Direct at pages 24-25.

modifications in compliance with additional guidance on NRC expectations for fire protection. Additional Prairie Island fire protection costs are included in this rate case, as described on pages 76 through 80 of my Direct Testimony.

As another example, in our 2010 rate case Mr. Koehl also addressed requirements in 10 CFR Part 73, which went into effect on May 26, 2009 and enhanced requirements for nuclear access controls, event reporting, security personnel training, safety and security activity coordination, contingency planning, radiological sabotage protection, and cyber security.[4] These regulations have been modified several times since then, and as illustrated by Mr. Weatherby's Exhibit___(SLW-1), Schedule 7, the Company has invested approximately $30 million in Prairie Island plant security-related initiatives between 2009 and 2015.

Further, in March of 2012, the NRC issued new Orders requiring additional public safety protections and emergency preparedness in response to the incident at Fukushima. These Orders have resulted in Fukushima capital expenditures at Prairie Island of approximately $43 million between 2012 and 2015, with additional program activities continuing into 2016 through 2019.

Combined with ongoing requirements associated with maintaining our operating license, these regulatory mandates have required substantial Company investments. The Company is obligated to satisfy these requirements to keep the plant operating, but they also mean that Prairie Island is operating with the benefit of additional safety and security enhancements for the protection of our customers and communities.

[4] Docket No. E002/GR-10-971, Koehl Direct at page 23.

Q. HOW HAS THE COMPANY BALANCED THESE MANDATED ACTIVITIES WITH THE NEED TO ADDRESS OVERALL PLANT AGING?

A. We have strategically prioritized when to make capital investments in aging equipment at Prairie Island, worked to manage capital costs overall, and updated our priorities as needed over time in order to manage plant operations as well as our obligations to the NRC, customers, and other stakeholders. That prioritization has enabled us to maximize the value of Prairie Island for a number of years while ensuring its safe and reliable operation.

Q. CAN YOU PROVIDE AN EXAMPLE OF PRIORITIZING INVESTMENTS?

A. Yes. As explained in my Direct Testimony in our rate case filings in Docket Nos. E002/GR-12-961[5] and E002/GR-13-868,[6] the Company completed the Prairie Island Unit 2 Steam Generator Replacement project at the end of 2013. This was a large and complex project, and similar steam generator replacements at other nuclear facilities have encountered problems that ultimately led to those plants' closures.[7] As such, our successful completion of this project required a substantial commitment of Company resources, including follow-up with vendors after project completion.

During this same timeframe, the Company's resources were constrained by other large projects both within and outside Nuclear. In addition to our increasing work at Prairie Island and Monticello, we were undertaking large investments in other Company infrastructure. Because we were operating our

[5] Docket No. E002/GR-12-961, O'Connor Direct at pages 26-27.
[6] Docket No. E002/GR-13-868, O'Connor Direct at pages 32-38.
[7] Docket No. E002/GR-13-868, O'Connor Direct at pages 35-36.

Prairie Island units effectively, we were able to defer some Prairie Island LCM projects and maximize the value of our existing plant systems.

Q. CAN YOU ELABORATE ON THE PERFORMANCE OF PRAIRIE ISLAND UNITS 1 AND 2 DURING THIS PERIOD?

A. Yes. Through 2014, both Prairie Island Units were performing exceptionally well. Between January 2, 2013 and our October 8, 2014 planned refueling outage, Prairie Island Unit 1 ran "breaker-to-breaker" – that is, consecutively, without any outage time – for 644 consecutive days. During this period, the unit's capacity factor was 97 percent. Prairie Island Unit 2 likewise ran breaker-to-breaker for 479 days before its September 2013 refueling outage, and was online the entire year of 2014 other than a brief shutdown in May. Although we continued to observe that equipment was aging, we did not engage in large-scale LCM work given the plant's performance.

However, the aging equipment would require LCM work at some point. In late 2014 and 2015 we experienced three forced outages at Unit 1 due to problems with seals related to reactor coolant pumps, a trip (when a plant automatically goes offline) at Unit 2 due to an instrumentation failure, a trip at Unit 2 due to a condensate motor issue, and a trip resulting from a crack on an oil line associated with the original generator at Unit 1. These issues, combined with the overall aging of our equipment, additional corrosion and degradation we are observing, and our ongoing risk assessments, create the need for the work we anticipate completing between 2016 and 2020.

IV. 2016-2020 MYRP CAPITAL INVESTMENTS IN LCM

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. In this section of my Supplemental Direct Testimony, I explain why the Prairie Island LCM work described in my Direct Testimony in this case should not be delayed beyond the term of this rate case. In my Direct Testimony, I supported the overall reasonableness of the Company's Prairie Island LCM project plans, scope, and costs. In light of the Commission's question whether to condition approval of recovery of the costs of this work on decisions about Prairie Island's future, in this Supplemental Direct Testimony I underscore why we need to complete this work – and therefore incur these costs – in the near-term regardless of the long-term future of Prairie Island.

Q. CAN YOU ELABORATE ON THE KIND OF DETAIL PROVIDE IN YOUR DIRECT TESTIMONY REGARDING PRAIRIE ISLAND PLANT REQUIREMENTS OVER THE TERM OF THE MULTI-YEAR RATE PLAN?

A. In my Direct Testimony, consistent with the support for Nuclear projects I provided in our last rate case, I walked through each key project to be completed at Prairie Island (and Monticello) in plan years 2016 through 2018 and demonstrated the need for each project and the reasonableness of our capital investment plan. I also provided support for the estimated costs of each key project included in our case. This discussion was not limited to LCM, but rather addressed all key projects being completed at Prairie Island during this 2016-2018 timeframe. My testimony also included identification of those specific projects we consider to be LCM work for 2016 through 2018,

and identified certain 2016-2018 LCM work that will continue into 2019 and 2020. Finally, I identified the capital additions that are associated with these key LCM projects and included our request for rate recovery.

Q. WHAT SPECIFIC PROJECTS DID YOU IDENTIFY IN YOUR DIRECT TESTIMONY AS PRAIRIE ISLAND LCM ACTIVITIES?

A. In my Direct Testimony, I identified five key LCM investments planned for 2016 through 2018: reactor coolant pump replacements, heater drain tank pump speed controls, motor rewinds/replacements, cooling tower replacements, and the main electrical generator replacement for Prairie Island Unit 1.[8] I also noted that the reactor coolant pump and cooling tower replacement projects were multi-year programs that would continue through 2019 and 2020, respectively.[9] I note that each of these projects fall within the Reliability capital budget grouping identified in my Direct Testimony.

Q. ARE THESE THE ONLY PROJECTS THE COMPANY IS INCLUDING IN ITS LCM ANALYSIS IN SUPPLEMENTAL DIRECT TESTIMONY?

A. No. As noted above, the definition of LCM activities does not necessarily confine itself to specific projects, but rather is based on the needs of a plant to manage its aging and the associated safety and reliability risks. To be conservative we have included all Prairie Island Reliability and Improvements capital budget grouping costs as LCM-related for purposes of Mr. Weatherby's comparison of actual and 2015 forecasts of 2008-2020 Prairie Island LCM costs to earlier estimates in the Certificate of Need docket.[10] While these rate

[8] O'Connor Direct at pages 88-98, 110-113, 121-124.
[9] O'Connor Direct at pages 89, 122.
[10] In his comparison of past LCM costs, Mr. Weatherby also discusses the role of the Steam Generator, which was part of our former "Strategic" capital budget grouping as described on pages 35-36 of my

case groupings include some smaller investments that are not strictly defined as LCM, they encompass all LCM spending.

Q. HOW DID THE COMPANY IDENTIFY THESE GROUPINGS AS INCLUSIVE OF ALL LCM?

A. As outlined above, LCM is defined as the aging management activities necessary to maintain the material condition of the plant in a safe and cost-effective manner. All of the key LCM projects at Prairie Island that I identified for 2016-2018 fall within the Reliability grouping. Further, a review of each current Nuclear capital budget grouping illustrates why the Reliability and Improvement groupings capture our 2016 through 2020 Prairie Island LCM activities.

- *Fuel:* This is not LCM work; fuel is a power source for the plant.
- *Dry Cask Storage:* Dry Cask Storage relates to care of spent fuel throughout and beyond the life of the plant, rather than aging of systems or equipment.
- *Mandated Compliance:* This grouping does not include LCM work, as Mandated Compliance projects relate to new operational and safety requirements placed on the plant. These projects are identified by NRC liaisons during inspections or result from issued rules, including rules that follow from larger nuclear incidents like the disaster at Fukushima Daiichi. As such, mandated compliance falls outside of normal aging management.
- *Reliability:* This grouping consists almost entirely of LCM activities, as Reliability investments are made for the specific purpose of ensuring that

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Direct Testimony. Since that project was completed and the Strategic grouping is no longer used, it is not relevant to the 2016-2020 capital additions I discuss in our current multi-year rate plan.

aging plant systems can safely and reliably continue to the end of the plant's licensed life. This grouping also includes some smaller reliability costs that are not specific to aging management, such as tool and small equipment purchases.

- *Improvements:* Improvements typically do not include LCM activities, as they are focused on improving output, operational performance, or efficiency. However, it is sometimes difficult to separate true upgrades from replacements of aged equipment, as an improvement in operation or design inherently tends to include replacement of some aging equipment.
- *Facilities and General:* Facilities management and general activities (which include plant building construction and maintenance, property maintenance, and other property management costs) are generally not considered LCM because they relate to maintaining property rather than operational equipment.

Q. WHAT ADDITIONAL PRAIRIE ISLAND LCM INFORMATION DO YOU PROVIDE IN THIS SUPPLEMENTAL DIRECT TESTIMONY?

A. My Exhibit___(TJO-2), Schedule 1 identifies all Reliability and Improvements capital additions included in this rate case for the 2016 through 2020 plan years, including explanations and business justifications why these projects are necessary in the short-term regardless of whether Prairie Island continues to operate beyond 2020. Mr. Weatherby similarly provides the associated information on a capital expenditure basis in his Exhibit___(SLW-1), Schedule 5.

In addition, I discuss our key Prairie Island LCM capital additions in more detail below, focusing on the need to complete these projects in the 2016 through 2020 timeframe given the aged condition of the plant systems.

B. Key LCM Projects 2016-2018

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. In this section of my Supplemental Direct Testimony, I explain why we plan to undertake the LCM work included in our current rate case in order to operate the plant in a safe and reliable manner over the next three to five years, and therefore why the associated costs should be approved regardless of any long-term decisions regarding the future of Prairie Island.[11]

Q. EARLIER YOU NOTED THAT THE COMPANY HAS PLANNED FIVE KEY LCM PROJECTS AT PRAIRIE ISLAND FOR THE 2016 THROUGH 2018 TIMEFRAME. HOW DO THOSE PROJECTS COMPARE TO THE OVERALL LCM WORK AT PRAIRIE ISLAND IN THIS CASE?

A. As illustrated on Exhibit___(TJO-2), Schedule 1, these five projects constitute 70 percent of the 2016-2018 capital additions in the Reliability capital budget grouping, and 60 percent of such additions for the period 2016-2020. These projects include:[12]

- Reactor Coolant Pumps (2016-2019), $41.5 million over four years
- Heater Drain Tank Pump Speed Controls (2016-2018), $20.5 million over two years

[11] December 22 Order at Issue 8 (asking the ALJ to address whether the PI LCM costs "authorized for cost recovery in the 2016 test year and 2017 and 2018 plan years should be considered provisional or placeholder amounts until the Commission makes a determination on the prudence of the Life Cycle Management costs at the Prairie Island plant").

[12] All dollars are in terms of capital additions, with AFUDC.

- Motor Rewinds/Replacements (2016-2019), $24.7 million over four years
- Cooling Tower Replacements (2017-2020), $68.4 million over four years
- Electrical Generator for Prairie Island Unit 1 (2018), $74.4 million in 2018

Q. CAN YOU PROVIDE MORE DETAIL EXPLAINING WHY THESE PROJECTS MUST BE COMPLETED DURING THE TERM OF THIS RATE CASE, EVEN IF THE COMMISSION DETERMINES THAT PRAIRIE ISLAND SHOULD NOT OPERATE TO THE END OF ITS EXTENDED OPERATING LICENSE?

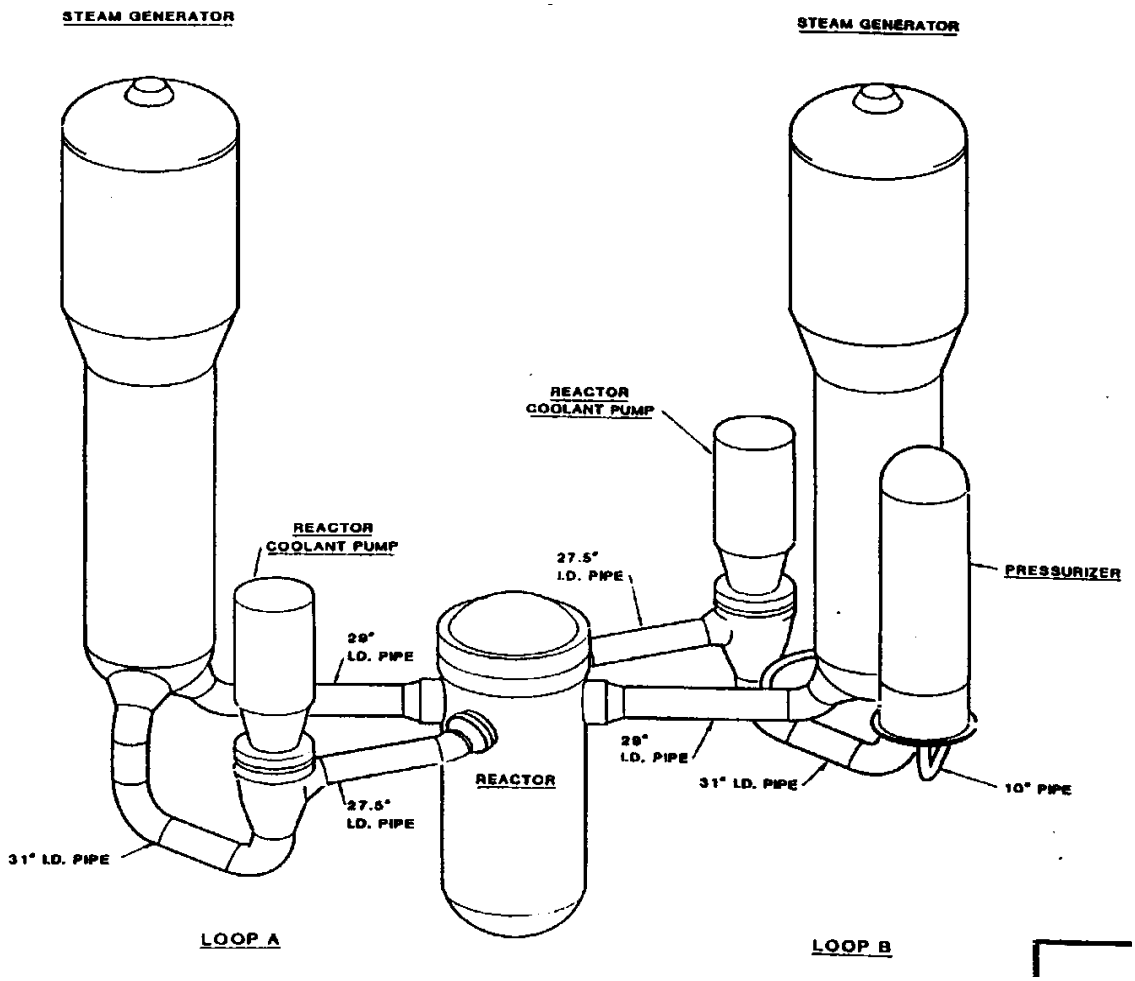
A. Yes. I will address each of these projects in turn, beginning with the reactor coolant pumps.

1. Reactor Coolant Pumps

Q. WHAT ARE REACTOR COOLANT PUMPS?

A. Reactor coolant pumps (RCPs) are large centrifugal pumps (two per unit) that are part of the generation system of the plant. The purpose of the RCPs is to transfer heated water from the reactor core to the steam generator, to help remove and transfer the amount of heat generated in the reactor core so steam can be produced to turn the generator and make electricity. Figure 1, below, illustrates the location of the RCPs in relation to the reactor and steam generator.

Figure 1: Reactor Coolant Pumps



RCPs are not in themselves considered safety systems, but their activity is necessary to control temperatures in the reactor and, thus, imperative to maintaining the safety of the reactor and plant.

Q. WHAT IS THE SCOPE OF THE REACTOR COOLANT PUMP REPLACEMENT PROJECT DURING THE MULTI-YEAR RATE CASE?

A. The reactor coolant pump project is a four-year project in which we expect to refurbish or replace the internal assemblies of each of the four aged RCPs at Prairie Island between 2016 and 2019. The Company presently has an old

used RCP that needs substantial work before it can be used in the plant as a rotating spare. The project involves refurbishing the old RCP into a viable spare (including replacing portions of the internal assemblies), installing it to replace one of the presently-operating, higher priority RCPs, and then refurbishing the removed RCP into another rotating spare. We will then rotate the second refurbished RCP with another operating RCP, and so on until we have four refurbished/replaced, functional RCPs and one refurbished spare.

Q. WHY IS IT NECESSARY TO REPLACE PRAIRIE ISLAND'S REACTOR COOLANT PUMPS IN THE NEXT FEW YEARS?

A. As discussed in my Direct Testimony,[13] the internal assemblies of our RCPs are a "single point vulnerability," which means that they are a critical component of the plant whose failure results in a reactor trip, turbine trip, or loss of generation capacity. Three of the four pumps at Prairie Island were manufactured around 1970, and are susceptible to shaft cracking[14] due to their age and design. The fourth RCP at Prairie Island was manufactured in 1984, and is therefore more than 30 years old. The current pump internal assemblies have never been refurbished. Over time, the rotating elements of the assemblies wear out due to fluid friction and lose their performance capacity and capability.

[13] O'Connor Direct at pages 88-89.

[14] The shaft is part of the internal assembly to the RCP, and transmits torque from the motor to the rotor that increases the flow and pressure of coolant. Reactor coolant pump shaft cracking has been an industry issue for more than 20 years, and there have been multiple indications of cracks at various Pressurized Water Reactor plant sites, including complete severance of two pump shafts at the Crystal River Nuclear site.

While the RCPs at Prairie Island functioned within acceptable limits through 2014, ongoing aging and degradation was assessed through vibration monitoring. In addition, as the RCPs have aged, small bits of metal are "spit out" of the pump, which is the most concerning degradation since it becomes debris in the water flow, and damages the RCP seals that hold radioactive water within the system. Further, the plant is permitted only very limited quantities of leakage pursuant to NRC regulations; higher quantities of leakage will cause the Company to take an outage to replace seals. Usually a seal outage takes approximately two weeks for replacement.

Q. HAS THE COMPANY ALREADY EXPERIENCED FORCED OUTAGES AS A RESULT OF THE REACTOR COOLANT PUMPS (INCLUDING THE SEALS)?

A. Yes. As discussed in my Direct Testimony,[15] in our October 2014 refueling outage we replaced the seals with new designs to address post-Fukushima/fire protection loss of inventory issues. Following that installation, we had three separate seal failures between the fourth quarter of 2014 and the spring of 2015, resulting in three separate forced outages at Prairie Island Unit 1. After a further re-design in the seal fact configuration, the seals have operated appropriately.

However, our RCP pump vendor, Westinghouse, determined that aging and degradation of our RCPs – particularly pump 12, which created the seal issues described above – is likely to create additional foreign material and result in additional damage to the components. The Company's phased program to replace RCP components between 2016 and 2019 is intended to address these aging issues in a measured way, mitigating the risk of safety problems and

[15] O'Connor Direct at pages 89-90.

further outages. It is a conservative operations strategy to address these issues on a planned basis, which is nearly always less expensive and disruptive to plant operations.

Q. DID THE COMPANY CONSIDER ALTERNATIVES TO REACTOR COOLANT PUMP REFURBISHMENT?

A. Yes. We considered five options: (a) running the pumps to failure; (b) the refurbishment of the spare and phased refurbishment of existing RCPs; (c) design changes that might allow more limited modifications to the existing RCPs; (d) redesigning the seals to reduce the impact of RCP degradation; and (e) replacing the RCPs with newer models.

We determined that we cannot run the RCPs to failure because they constitute a single point vulnerability to the primary coolant system's integrity and therefore presents a potential nuclear safety issue. Given the failures we have already experienced and the age of the RCPs, delaying our efforts to address the RCPs presents a significant risk of additional outages during this period. Moreover, as the RCP failures drive additional outages, we face the risk of a degraded NRC Column status, and the regulatory scrutiny and additional costs associated with that downgrade.

As discussed above, we have redesigned the seals in a manner that appears to reduce the impact of RCP degradation, but we and our vendor do not have sufficient proof that the seal redesign will address the overall problems with the RCPs' age and degradation. A design change, on the other hand, was not found to be a viable economic solution given the overall design of the plant and the vendor's limited fabrication services and extremely long lead times.

Finally, we do not have the option to replace the RCPs with newer models because useable equipment is not being commonly manufactured anymore, given the age of the equipment and that new nuclear construction is relatively rare.

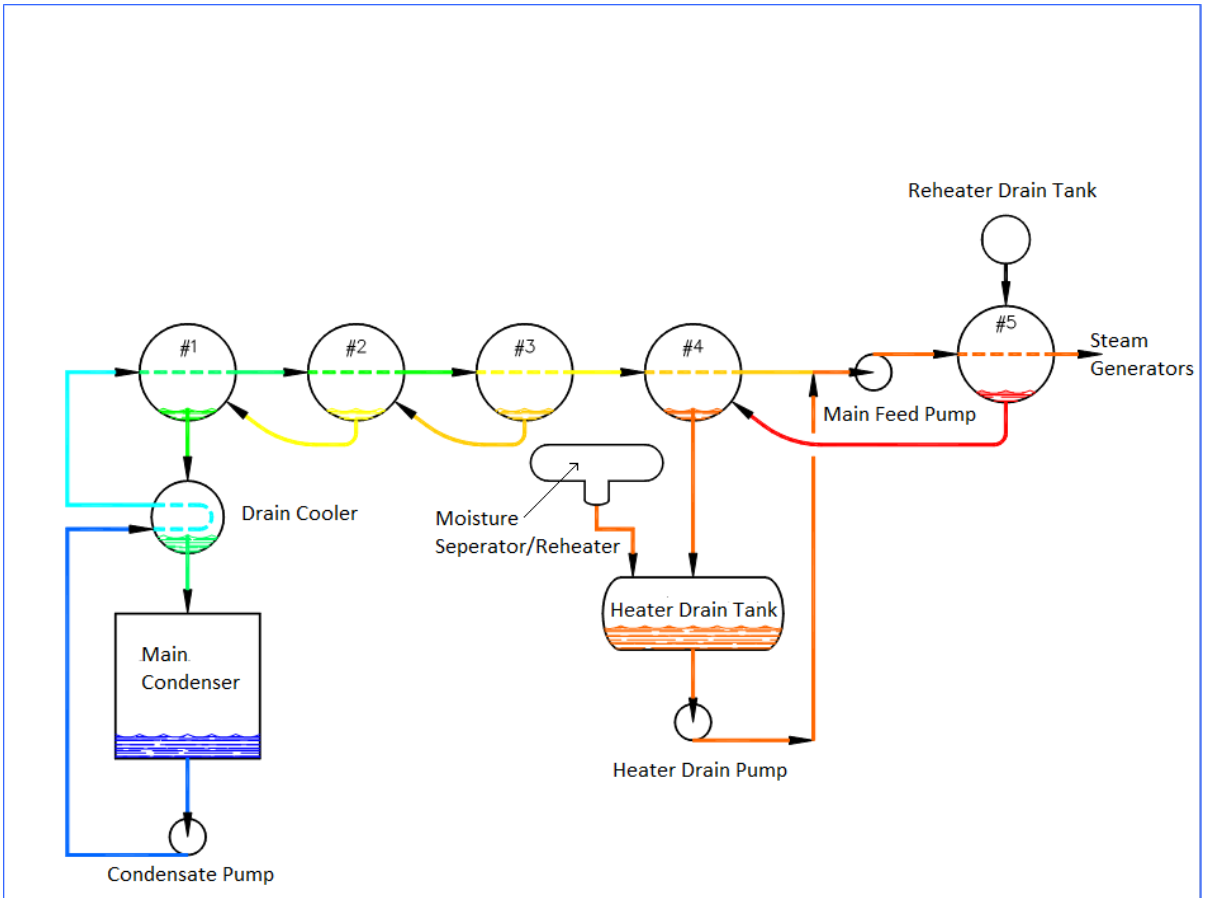
Therefore, we have concluded that the phase refurbishment/internal assembly replacement with the newer, more robust seals is the most viable and cost effective option to ensure safe and reliable plant operation in the near term.

2. Heater Drain Tank Pump Speed Controls

Q. WHAT ARE HEATER DRAIN TANK PUMP SPEED CONTROLS?

A. These controls establish the speed of the pump motors, which is proportional to reactor power. The heater drain system controls condensed, excess heated water which is pumped from the heater drain tank back to the reactor to maximize the power generation of the plant. Put differently, the heater drain tank collects the excess water that has condensed from steam that flowed through the condenser, then reheats the water for use in the reactor. The heater drain tank pumps (three per unit) propel the water to the reactor. Figure 2, below, provides an illustration of the heater drain tank and pump.

Figure 2: Heater Drain Tank and Pump



This heater drain process is necessary when a Unit is operating at high production levels, because there is so much condensate that needs to be collected. Pumping this warmed water forward to the reactor in a controlled manner is necessary to bring the plant from roughly 75 percent power production to nearer 100 percent production.

Q. DID THE COMPANY CONSIDER OPERATING THE PLANT AT LESS THAN FULL POWER AND NEVER USING THE HEATER DRAIN TANK OR PUMPS (AND THEREFORE NOT REQUIRE NEW SPEED CONTROLS)?

A. Yes, but we concluded this is not a realistic option. The plant is designed so that if the heater drain tank doesn't function, the plant automatically drops to 80 percent production. So in the very short term, it is possible to operate without the heater drain tank. However, the plant is not designed or licensed by the NRC to operate without heater drain tanks over multiple years. As such, we would be at risk of not meeting NRC key performance indicators (KPIs) such as limits on how often a plant can have unplanned power reductions of 20 percent or more (a "transient").[16] If the plant hits a certain threshold of transient events, the NRC will degrade the site's Column performance status. The NRC would likely require us to apply for a license amendment to permit operation without a functional heater drain tank system. An NRC license amendment is an expensive, long-lead-time process and does not come with the guarantee of a successful result. The plant is required to operate systems in accordance with the design that was previously licensed until the NRC grants a deviation or change to that licensed design.

Q. WHY IS IT APPROPRIATE TO COMPLETE THIS PROJECT IN THE NEXT FEW YEARS?

A. We are presently undertaking significant operations and maintenance efforts to keep all pumps operating, but this strategy is only partially effective. While we have explored the option of continuing to address issues as they arise through existing maintenance repair functions, rather than replacing the controls with more functional components, we believe we have already delayed the project long enough and have exhausted our current means to sustain reliable performance through maintenance.

[16] This KPI is designed to give early warning of potential safety issues.

Further, additional aging of these controls creates a greater risk of additional transient events (loss of power) and NRC involvement. As of July 2015 we were experiencing 1 to 2 transient events and 17 low level unplanned reactor power changes (reactivity events) per year at Prairie Island, creating a significant maintenance burden. Also, critically, based on the NRC's continued raising of standards, any transient event is now considered a challenge to the reactor, such that no more than six transient events in any 12-month period are permitted without an automatic column downgrade. We are particularly concerned because the current heater drain tank pump speed control system is antiquated – it is an early electrical system, circa 1970s, that is difficult to manage within required ranges. Even under close supervision and maintenance, we do not believe this technology is sufficient to avoid six transients in a 12-month period going forward, and therefore its continued use presents higher nuclear operating risk.

Finally, we have previously experienced the simultaneous loss of function in all three pumps at one unit, thereby reducing our output and requiring significant O&M attention to repair the problems. Each year we tend to be on the threshold of reaching our NRC transient limit at each Prairie Island Unit, which threatens our NRC Column performance status, a forced outage to address the overall issue, or a reactor trip if the power change were large enough. As a result, we believe it is important to address these systems now.

3. Motor Rewinds/Replacements

Q. WHAT MOTORS DOES THE COMPANY INTEND TO REWIND OR REPLACE AT PRAIRIE ISLAND BETWEEN 2016 AND 2018?

A. While we have many motors at the plant since every water system has a pump

and every pump has a motor, this project focuses on a phased approach to rewinding or replacing 52 motors that run at all times and are original to the plant. As noted in my Direct Testimony, industry guidelines and our equipment manufacturers recommend refurbishment of motors at 10-15 years and rewinds every 30-40 years. The 52 motors included in this project, such as condensate water pump motors, reactor coolant pump motors, cooling tower pump motors, horizontal cooling water pump motors, residual heat removal (RHR) pump motors, and feedwater pump motors, are more than 42 years old and have been maintained but have not been rewound or refurbished.

Q. WHY HASN'T THE COMPANY REPLACED OR REWOUND THESE MOTORS BEFORE NOW?

A. As part of our aging management program, we have conducted motor testing during each outage. During these inspections and tests, we stress test motors, check equipment, review insulation, and the like. These inspections and maintenance work on motors tend to lengthen our outages, but for a number of years our efforts indicated it was not yet necessary to make capital investments to replace or rewind these motors.

Q. WHY IS IT IMPORTANT TO COMPLETE THIS MOTOR REWIND/REPLACE PROJECT IN THE NEXT FEW YEARS?

A. A number of our motors are now well beyond their expected operating lives and are beginning to degrade and fail. We are finding that the metal in these motors tends to break down after approximately 40 to 45 years of operation. Under such circumstances, an aged motor could pass a performance test upon inspection but a short time later experience a metal breakdown and failure.

We experienced this outcome in the spring of 2015, when a condensate motor failed due to aging and caused a trip (automatic outage) at Prairie Island Unit 2. Other possible impacts of motor failures include forced outages, a further trip, a transient event, or an inability to meet NRC license conditions to operate if motors or safety systems are deemed non-functional.

Q. WHAT ALTERNATIVES TO MOTOR REWINDS/REPLACEMENTS DID THE COMPANY CONSIDER?

A. First, we considered the option to continue a maintenance strategy and further delay the motor replacements and rewinds. For the reasons noted above, we do not believe continued inspections and maintenance will be sufficient to keep the motors operating reliably and safely, since failure often occurs in an unpredictable manner. Second, we considered replacing our current motors with high efficiency motors rather than equivalent motors, but determined that this approach would require costly and complex design changes and could have an adverse effect on electrical loading margins. Third, we considered the options of rewind versus replace for each aged motor. The rewind option tends to offer no cost savings due to repair discoveries and limited warranties and service lives. In each instance we selected the option that made the most sense for the motor(s) in question. Our phased approach to motor rewind and replacement presented the most reasonable and effective option. We will continue to need to address other aging motors beyond 2018, but expect those efforts to address a more limited number of motors in each year.

4. Cooling Towers

Q. WHAT ARE COOLING TOWERS?

A. Cooling towers are structures constructed for plant cooling and to protect

aquatic environments. They serve the dual purpose of ensuring (1) adequate cooling water is available to run the plant, and (2) water returned from the Prairie Island plant to the Mississippi River is at appropriate temperatures to protect river flora and fauna pursuant to our state environmental discharge permits.

Q. WHAT IS THE SCOPE OF THIS PROJECT?

A. As discussed in my Direct Testimony, the project is focused on refurbishing virtually all aspects of the cooling towers, including updating the hot water distribution header system and making sure the main structure is sound. We also anticipate refurbishing underground piping, replacing cooling tower transformers, and undertaking other mechanical replacement (some of which will occur in 2019 and 2020). Overall, we anticipate completing refurbishment of one cooling tower each year from 2018 through 2020.

Q. WHY IS IT NECESSARY TO REFURBISH PRAIRIE ISLAND'S COOLING TOWERS OVER THE NEXT FEW YEARS?

A. The four cooling towers at Prairie Island are original to the plant, and have been operating for nearly 44 years. A photograph of these 1970s-era structures is set forth as Figure 3 below.

Figure 3: Prairie Island Cooling Towers

We have undertaken a maintenance repair strategy to maximize use of the original towers, but they are now well beyond their anticipated useful life. We are frankly at the point where applying patches to the towers is not expected to be a feasible option for much longer, so the towers need to be refurbished or replaced.

If we do not address the aging of the cooling towers and they become structurally unsound or do not function, we cannot operate the plant due to loss of cooling capability. Our additional objective is to minimize the risk that a water distribution header (the main pipe transmitting hot water) could fail, resulting in the collapse of a cooling tower cell. The age of piping in the

towers and the loss of header flexibility due to repeated repairs increase this risk.

Even if the cooling towers operated in part, we are at risk of losing the ability to bring water that will be discharged to the Mississippi River to the proper discharge temperature. Failing to control water discharge would endanger local wildlife, would put us at risk of violating our discharge permits from the Minnesota Pollution Control Agency, and also could result in a requirement that we stop or reduce plant output to meet limitations on thermal discharge to the river.

Q. WHAT ALTERNATIVES TO THE COOLING TOWER REPLACEMENT PROJECT DID THE COMPANY CONSIDER?

A. The Company did consider continuing a maintenance strategy, but we believe the condition of the towers will result in unanticipated scope increases for that approach, causing maintenance costs to be large and unpredictable, and will ultimately require a major replacement of components anyway. We also considered whether to find whole, new cooling towers to simply replace our existing cooling towers rather than refurbishing or rebuilding them. However, to date we have not been able to identify a vendor who could provide new replacement towers; therefore, this option is not presently viable. Consequently, we believe completing the phased cooling tower refurbishment between 2018 and 2020 is a necessary approach to ensure the safe and reliable operation of the plant.

5. Electric Generator (Unit 1)

Q. WHAT IS THE ELECTRIC GENERATOR AT PRAIRIE ISLAND UNIT 1?

A. The electric generator is connected to the turbine and is the main final component of the plant in the production of electricity. The turbine is powered by steam from the steam generator, and rotates the electric generator to create electricity. The Prairie Island Unit 2 electric generator was replaced in 2015, and was a Step project in our prior rate case.

Q. WHY IS IT NECESSARY TO UNDERTAKE THIS PROJECT BY 2018?

A. Our electrical generator at Prairie Island Unit 1 is original to the plant, and at 42+ years of use has already operated longer than any similar generator in the industry. The generator has experienced several thermal cycle events during the current operating cycle, and our original equipment manufacturer and industry experts have indicated that the likelihood of future issues is not fully predictable. As noted in my Direct Testimony, we originally planned to complete this project in 2016, but delayed it until 2018 due to resource restraints. A planned test in 2016 will inform the Company whether delaying this project to 2018 remains viable.

The risks of not completing this project in the planned timeframe include equipment failures resulting in forced outages or plant trips – potentially for an extended period, given the importance of the generator to the power production process. These same risk factors also place us at risk of not meeting NRC KPIs or incurring additional regulatory requirements to ensure safe and reliable plant operation, such as trips or unplanned power changes of 20 percent or more.

Q. WHAT ALTERNATIVES DID THE COMPANY CONSIDER?

A. As I discussed in our last Minnesota rate case,[17] the Company originally anticipated rewinding the electric generators for both Prairie Island units rather than replacing them, but determined during the planning and bidding phases that replacing the generators was more cost effective. In addition to overall value and the higher O&M associated with a rewound generator, we would have to conduct an inspection of a rewound generator within 10 years of the rewind, which requires a lengthy outage process. By purchasing a replacement generator, we anticipate avoiding the need for that inspection and the ability to utilize the generator through the end of the current plant's life with significantly less inspection/maintenance work.

Based on the long lead times associated with such projects and our anticipated needs, we have already ordered and received the Unit 1 electric generator with the plan to install it in 2018. Delaying replacement of the generator beyond 2018 is no longer reasonably feasible; rather, it may become necessary to advance this replacement.

Q. WHAT LCM WORK HAS THE COMPANY PLANNED AT PRAIRIE ISLAND FOR THE TERM OF THIS RATE CASE, IN ADDITION TO THE FIVE KEY LCM PROJECTS DESCRIBED ABOVE?

A. LCM capital additions are planned at Prairie Island throughout the term of the rate case to replace or refurbish aging equipment in several key systems of the plant, including generation systems, electrical systems, cooling systems, control systems, and fuel systems. Exhibit___(TJO-2), Schedule 1 lists out the capital additions for the various projects planned for 2016-2018. The largest LCM

[17] Docket No. E002/GR-13-868, O'Connor Direct at pages 74-75.

additions other than the five key projects described in my Direct Testimony are for 2018 through 2020 replacements of Prairie Island transformers and the Foxboro Control Module. Those two projects are discussed in the next section of my testimony

C. Additional LCM Projects 2019-2020

Q. DOES THE COMPANY'S RATE CASE FILING ALSO PROVIDE INFORMATION ABOUT PRAIRIE ISLAND LCM FOR 2019 AND 2020?

A. We provide full forecasts for the Company for each of the next five years, but do not provide significant detail regarding particular projects in 2019 and 2020. As Company witnesses Aakash H. Chandarana notes in his Direct Testimony, our five-year proposal "is a completely separate proposal from our three-year MYRP request . . . . [and is] a test year built from our 2016 cost of service plus four static, formulaic, incremental rate increases."[18]

However, in light of the Commission's December 22 Order seeking information about Prairie Island LCM through 2020, Mr. Weatherby and I provide this information in our Supplemental Direct Testimony. I discuss the capital additions currently in our 2019-2020 forecast, while Mr. Weatherby provides comparisons of anticipated capital expenditures through 2020 to our earlier estimates in Certificate of Need proceedings and to our current Resource Plan filing.

Q. WHAT LEVEL OF DETAIL CAN THE COMPANY PROVIDE REGARDING ITS PLANS FOR PRAIRIE ISLAND LCM IN 2019 AND 2020?

A. Exhibit___(TJO-2), Schedule 1 identifies our current capital addition budgets

[18] Chandarana Direct at page 69.

for 2016 through 2020 for the Prairie Island Reliability and Improvements budget groupings. It is important to note, however, that like all areas of the Company we are likely to experience emerging issues over the next four to five years that will need our attention and cannot be fully predicted now. This is particularly true of Nuclear operations, given industry changes and increased federal regulation and oversight of nuclear plants in recent years. We will continue to refine our Prairie Island LCM plans over time, but included our best available 2019-2020 estimates in the forecast for this rate case.

Q. WHAT PRAIRIE ISLAND LCM WORK DOES THE COMPANY ANTICIPATE WILL RESULT IN CAPITAL ADDITIONS IN THE 2019 AND 2020 TIMEFRAME?

A. As discussed in my Direct Testimony in this proceeding, we do anticipate that the Reactor Coolant Pump and Cooling Tower projects described above will result in capital additions through 2019 and 2020, respectively. We expect the Motor Rewind projects to extend into 2019 as well. Combined, these projects account for approximately 59 percent of our Reliability and Improvements groupings for 2019, and 40 percent for the two years of 2019-2020.

We also anticipate other routine LCM investments in 2019-2020, as identified and supported in Exhibit___(TJO-2), Schedule 1. The largest projects we presently anticipate for 2019 and 2020, other than those identified above, are electrical system work for power transformer replacements and refurbishments throughout the plant and control systems work for replacement of the Foxboro Control Module for the plant control room operators. Each of these projects includes some initial capital additions in 2018, with the larger capital additions in 2019 to 2020.

Q. WHAT TRANSFORMERS DOES THE COMPANY PLAN TO PLACE IN SERVICE DURING THE MULTI-YEAR RATE PLAN?

A. The Company plans to replace several transformers at Prairie Island Units 1 and 2 in 2018 through 2020. The plant has several types of transformers. In 2014 and 2015, we replaced the Unit 1 and 2 Generation Step-Up (GSU) transformers that increase the voltage of the power produced at the plant for transmission to customers. The plant also has step-down transformers that reduce the voltage of power entering the plant, as well as start-up transformers and system auxiliary transformers. The transformers that were not replaced as part of the GSU transformer projects are all more than 40 years old and past the end of their expected useful lives and longer than the operating experience of the industry. We are therefore undertaking a phased approach to replacing these transformers over time. Transformers and reliable power sources are critical to post-Fukushima readiness at nuclear power plants, and are viewed by the NRC as equipment essential to defense-in-depth.

Q. WHY IS IT IMPORTANT TO REPLACE THESE TRANSFORMERS IN THE NEXT FEW YEARS?

A. While the transformers have functioned reasonably well in recent years, they are beyond their expected useful lives and we have observed their continual aging with small traces of internal gassing in oil samples, which are typical signs of internal breakdowns in materials. If a transformer fails while the plant is generating power, the associated Unit automatically trips, which creates not only an NRC transient but also a loss of production capability until the problem is resolved. Reductions in transformer performance or multiple failures will also result in increased NRC oversight given their safety significance and concerns about emergency preparedness efforts. Because we

are required to have two independent power supplies to run the plant, the loss of a transformer creates potential concerns with both regulators and the industry even if it does not immediately impact our ability to operate the plant.

While we can continue to operate the plant and maintain the transformers to some extent, we believe it is prudent and operationally conservative to continue to address this aging equipment as we have done with the GSU transformers.

Q. WHAT IS THE FOXBORO CONTROL MODULE?

A. The Foxboro Control Module is the control center of the plant, which consists of a large set of control devices and modules that monitor all aspects of plant performance and communicate with other plant systems, integrating the intervention and decision making capabilities for control room operators. Our existing control modules are the 1970s-era analog systems implemented with original construction of the plant.

Q. WHY IS IT IMPORTANT TO REPLACE THE FOXBORO CONTROL MODULE IN THE NEXT FEW YEARS?

A. This system is critical to the overall operations of the plant and necessary to meet our license requirement for Prairie Island, for they monitor the license conditions of the plant such as thermal power and temperature in the reactor. While the existing control modules currently function, they need frequent maintenance, and replacement parts are not readily available due to their age. In recent years we have replaced failed parts through a combination of designing our own replacement parts, attempting to repair or refurbish the failed part, or finding replacement parts from nuclear plants that have ceased

operation. That supply is finite and dwindling, and it is not clear whether we could find sufficient replacement parts to continue this repair approach in the event of a failure.

Q. WHAT DO YOU CONCLUDE ABOUT THE NEED FOR PRAIRIE ISLAND LCM IN THE 2019-2020 TIMEFRAME?

A. As with 2015-2018, we will need to make certain investments to address our obsolete and aged systems to keep the Prairie Island units running in a safe and reasonably efficient manner during those years. The key projects I have identified for all of the 2016 to 2020 timeframe are focused on meeting the immediate needs of the plant, and are therefore reasonable investments regardless of the long-term decisions we and our stakeholders need to make with respect to our nuclear facilities.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve recovery of the Nuclear capital investments proposed in our pending Minnesota electric rate case. The Company has provided detailed support for the reasonableness of our investments and costs, and illustrated that our planned investments at Prairie Island are necessary between 2016 and 2020 to maintain overall plant operations in a safe and reliable manner.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, it does.

Prairie Island Nuclear Plant
Capital Additions - Reliability & Improvement Groupings including LCM
Forecast Estimate Used for 2016 Test Year Rate Case

	System	2016	2017	2018	2019	2020	5 Year Total
LCM Projects Discussed in O'Connor Testimony							
Reactor Coolant Pumps (RCP) rebuilds	Generation Systems	$ 11,408,763	$ 9,191,062	$ 10,472,946	$ 10,382,239	$ -	$ 41,455,011
Heater Drain Tank Speed Controls upgrade	Control Systems	$ 10,436,924	$ 9,983,624	$ 141,336	$ -	$ -	$ 20,561,884
Motor Rewinds & Replacements	Aging Mgmt - multiple	$ 6,567,427	$ 9,176,165	$ 3,598,209	$ 5,340,558	$ -	$ 24,682,359
Cooling Tower/Water system replacement	Cooling Systems	$ -	$ 16,229,054	$ 19,319,442	$ 14,920,391	$ 17,936,810	$ 68,405,696
Electric Generator Replacement	Generation Systems	$ 308,802	$ -	$ 74,380,649	$ 60,000	$ -	$ 74,749,451
Subtotal - LCM Projects Discussed in Testimony		$ 28,721,917	$ 44,579,904	$ 107,912,582	$ 30,703,188	$ 17,936,810	$ 229,854,401
Portion of Total Reliability Additions		*60%*	*70%*	*73%*	*59%*	*26%*	*60%*
Other Reliability Projects - Mainly LCM	System						
Transformer replacements	Electrical Systems	$ 300,000	$ -	$ 11,445,088	$ 484,716	$ 29,185,311	$ 41,415,115
Foxboro Control Module replacement	Control Systems	$ -	$ -	$ 14,184,893	$ 13,872,813	$ 8,264,675	$ 36,322,382
Battery Room & Feedwater Pump Room Cooling	Cooling Systems	$ 2,907,802	$ 5,916,330	$ -	$ -	$ -	$ 8,824,132
Plant Process Computer System upgrade	Control Systems	$ -	$ -	$ 8,415,580	$ -	$ -	$ 8,415,580
Screenhouse header pipe replacement	Cooling Systems	$ -	$ 5,084,945	$ -	$ -	$ -	$ 5,084,945
Fan Coil Unit replacement	Cooling Systems	$ 4,866,101	$ -	$ -	$ -	$ -	$ 4,866,101
Change Fuel Cycle to 24 months	Fuel Systems	$ -	$ -	$ -	$ 4,957,051	$ -	$ 4,957,051
Radiation Monitor upgrade	Control Systems	$ 2,721,574	$ 498,480	$ -	$ -	$ -	$ 3,220,054
Safeguard pump redesign	Cooling Systems	$ 5,052,091	$ -	$ -	$ -	$ -	$ 5,052,091
Voltage Regulator replacements - Diesels	Control Systems	$ -	$ -	$ -	$ 984,058	$ 984,189	$ 1,968,246
Voltage Regulator replacements - Generator	Generation Systems	$ 21,525	$ -	$ 1,943,155	$ 9,000	$ -	$ 1,973,680
Other Reliability projects:		$ -	$ -	$ -	$ -	$ -	$ -
Various Cooling System upgrades & replacements	Cooling Systems	$ 692,740	$ 1,024,298	$ 334,937	$ -	$ 4,784,017	$ 6,835,992
Various Control System replacements	Control Systems	$ 414,029	$ 4,460,558	$ 2,469,418	$ -	$ -	$ 7,344,005
Emergent Work	Various	$ -	$ -	$ -	$ -	$ 7,074,388	$ 7,074,388
Minor Tools & Equipment - capital	Various	$ 574,722	$ 574,722	$ 574,722	$ 600,000	$ 600,000	$ 2,924,166
Minor Improvements - capital	Various	$ 946,812	$ 947,045	$ 947,065	$ 463,665	$ 412,261	$ 3,716,849
All Other Reliability	Various	$ 871,047	$ 383,016	$ -	$ -	$ 300,000	$ 1,554,063
Total PI Capital Additions - Reliability Grouping		$ 48,090,360	$ 63,469,298	$ 148,227,441	$ 52,074,491	$ 69,541,651	$ 381,403,241
Improvement Projects	System	2016	2017	2018	2019	2020	5 Year Total
Information Technology capital improvements	Control Systems & Other	$ 565,000	$ 390,000	$ 390,000	$ 390,000	$ 390,000	$ 2,125,000
Vibration Monitoring Upgrades - Turbine/generator	Gen/Control Systems	$ 10,072	$ -	$ 2,551,763	$ 15,000	$ -	$ 2,576,835
Total PI Capital Additions - Improvements Grouping		$ 575,072	$ 390,000	$ 2,941,763	$ 405,000	$ 390,000	$ 4,701,835

Prairie Island Nuclear Plant
Capital Additions - Reliability & Improvement Groupings including LCM
Forecast Estimate Used for 2016 Test Year Rate Case

LCM Projects Discussed in O'Connor Testimony	System	Project Justification
Reactor Coolant Pumps (RCP) rebuilds	Generation	Reactor coolant pumps are past 40-year useful life. RCPs are releasing debris into water and seals in internal assemblies have failed. Need to replace for continued reliable operations in near term.
Heater Drain Tank Speed Controls upgrade	Control Systems	1970s-era analog system is past expected useful life. Significant O&M needed to maintain equipment, and is only partially effective; experiencing 1-2 transient events and 15-20 low level unplanned reactor power changes per year.
Motor Rewinds & Replacements	Aging Mgmt-Multiple	52 motors to be replaced are beyond useful life and inspections indicate degradation. Failed condensate motor caused 2015 plant trip; delaying project risks additional trips or transient events.
Cooling Tower/Water system replacements	Cooling Systems	Towers well beyond useful life; patches no longer sufficient for future structural integrity. Cooling tower functional issues create plant operational and discharge permit issues.
Electric Generator Replacement - Unit 1	Generation Systems	Generator has run longer than any in industry. Initially planned replacement in 2016, but delayed to 2018. Safety and reliability analysis in 2016 may require moving work back to 2016.

Other Reliability Projects - Mainly LCM	System	Project Justification
Transformer replacements	Electrical Systems	Transformers are showing signs of degradation due to aging. These transformers' design life is 40 years, which has now been exceeded. These transformers supply offsite power to the site's critical electrical buses.
Foxboro Control Module replacement	Control Systems	Obsolescence and continued degradation has caused an increasing rate of instrument failures in plant control systems, with an average of over 60 failures per year. Equipment failures have caused numerous plant transients and reactivity events. Cannot refurbish because spare component parts are in very low supply, when available. In addition, replacement parts of Westinghouse Distributed Processing Family (WDPF) system are no longer available. Westinghouse will not provide support for system after January 2018.
Battery Room & Feedwater Pump Room Cooling	Cooling Systems	The Battery Room and Auxiliary Feedwater Rooms are both in operable condition but presently non-comforming to the site's design basis. Components in the Battery Rooms are susceptible to overheating in a Design Basis Accident with a coincidental loss of offsite power. New room heat up calculations have indicated temperatures exceed some equipment design temperatures during certain accident scenarios. Restoration of cooling systems necessary to address these issues.
Plant Process Computer System upgrade	Control Systems	Reduces risk of future issues due to hardware failures. Loss of certain portions of the ERCS Data Acquisition System have significant effect on plant operations.
Screenhouse header pipe replacement	Cooling Systems	Microbiologically induced corrosion has resulted in piping replacement and emergent modification to address identified wall thinning and pinhole leaks. This replacement is necessary for code compliance and to reduce the risk of Unit shutdowns due to loss of the header.
Fan Coil Unit replacement	Cooling Systems	Due to recent degraded performance (coil leaks and leaks at the head tube sheet interface), the coils need to be replaced to eliminate potential plant derate or shutdown due to inability to perform safety related functions.
Change Fuel Cycle to 24 months	Fuel Systems	Transferring from an 18 month to 24 month fueling cycle expected to result in significant cost savings by reducing the number of outages per plant by 2 through the remainder of our current license period.

Prairie Island Nuclear Plant
Capital Additions - Reliability & Improvement Groupings including LCM
Forecast Estimate Used for 2016 Test Year Rate Case

Other Reliability Projects - Mainly LCM	**System**	**Project Justification**
Radiation Monitor upgrade	Control Systems	Aging and obsolescence issues regarding Radiation Monitoring system equipment. These monitors are original equipment (35 years old) and are two model generations old.
Safeguard pump redesign	Cooling Systems	We need to address the current design to enable an appropriate response to any failure of safegaurds cooling water pump components.
Voltage Regulator replacement - Diesels	Control Systems	The voltage regulator is obsolete and parts are not available. The voltage regulator is at the end of its life and loss of the regulator results in an extended Unit 1 shutdown.
Voltage Regulator replacement - Generator	Generation Systems	Continued dependence on the obsolete end-of-life asset imposes risks of unacceptable voltage fluctations to main electric generator. The voltage regulator is original plant equipment.
Other Reliability projects:		
Various Cooling System upgrades & replacements	Cooling Systems	Various upgrades and replacements to aging cooling systems, including coolers/chillers, valves, screens, and pumps.
Various Control System replacements	Control Systems	Various upgrades and replacements to aging control systems, including annunciators, switches and dampers.
Emergent Work	Various	Routine work order for capital needs currently not specified but likely to emerge (based on past experience).
Minor System Improvements - capital	Various	Routine work order for capitalized tools needed during ongoing work at plant.
Minor Tools & Equipment - capital	Various	Small emerging system improvement projects that meet Company capitalization criteria.
All Other Reliability	Various	Upgrade to aging polar cranes and installation of new security trap.

Improvement Projects	**System**	**Project Justification**
Information Technology capital improvements	Control Systems & Other	Routine work order for reliability issues with IT equipment on-site. Used for property ready made, minor in nature, maintenance related that meets the Capitalization policy, or may have minimal installation period to assist in plant operations.
Vibration Monitoring Upgrades - Turbine/generator	Gen/Control Systems	The current systems are obsolete. This upgrade represents the current industry's and Xcel Energy's in-house standard for detection and monitoring Turbine Generator component issues. Monitoring protects assets, the plant and personnel from safety issues and plant trips.